LPPC
www.lppc.org

The Large Public Power Council

1050 Thomas Jefferson Street NW, 7th Floor, Washington, DC 20007 • 202/298-1856 (phone) • 202/338-2361 (fax)

September 21, 2005

By Email

Mr. David H. Meyer
Acting Deputy Director
Office of Electricity Delivery and
Energy Reliability
U.S. Department of Energy
Washington, D.C. 20585

Dear Mr. Meyer:

On behalf of the Large Public Power Council ("LPPC"), this letter responds to stakeholder survey distributed by DOE in connection with the mandate in Section 1234 of the Energy Policy Act of 2005 directing the Department to study procedures governing electric utility economic dispatch. LPPC is an organization comprising 23 of the nation's largest locally-owned and controlled power systems. A list of LPPC members is attached. LPPC was made aware of the DOE survey by counsel for the American Public Power Association ("APPA"), an organization in which LPPC members also belong.

Although individual LPPC members may respond individually to the DOE survey, LPPC responds as a trade association in order: to (1) provide a general overview of its members' economic dispatch procedures; (2) correct an oversimplification of the criteria governing economic dispatch process; and (3) respond to what LPPC fears is a predilection implicit in the survey to promote some form of mandatory economic dispatch rule or regulatory protocol favoring non-utility generation.

I would also ask that you provide me with a timely copy of any report that the Department of Energy submits to Congress or the States on the results of the study conducted pursuant to Section 1234 of the Energy Policy Act of 2005, including any suggested legislative or regulatory changes. Thank you in advance for that consideration.

Question 1

"What are the procedures now used in your region for economic dispatch? Who is performing the dispatch (a utility, an ISO or RTO or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area?"

Response:

Those LPPC members operating within ISO control areas will respond separately. Those outside ISOs employ unit commitment programs to schedule the generation resources, including power purchases that will be needed to meet their daily load obligation. In addition, they each utilize energy management systems to perform the economic dispatch of generation in real time. The unit commitment program models operating characteristics of each purchase and plant. Included in the modeling of each plant are the heat rates, fuel costs, start-up costs, minimum run times, emission limits and costs, etc. The model then produces a schedule for dispatching the plants and purchases that minimizes total operating costs over the period being considered. The economic dispatch energy management systems use incremental heat rates, incremental fuel prices and emission costs to dispatch all available on line generating resources and power purchases to achieve the lowest possible production cost. After this "pure" economic dispatch is developed, reliability and other constraints, addressed in Question 2 below, are reflected in the dispatch protocols.

Economic dispatch is generally arranged on a day-ahead basis, taking into account variables such as unexpected loss of generation, changing system conditions and load forecasts. The process by which all of these variables are considered on a day-ahead and real-time basis is organized well in advance of the day-ahead market, and may involve planning years in advance. In addition, for many LPPC members, economic dispatch takes into account resources well outside their immediate Control Areas. As with resources within the immediate Control Area, the use of external resources is driven by price, deliverability and the reliability of the provider, all of which are used to ascertain the lowest cost, reliable resource.

Significant differences in dispatch protocols are observed in Pacific Northwest, where hydropower is relied upon extensively. In that setting, operational and associated statutory requirements dictate priorities for dispatch that do not necessarily follow least cost signals.

Question 2

"Is the Act's definition of economic dispatch (see above) appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?"

Response:

a. Definition

Section 1234(b) stipulates: "The term 'economic dispatch' when used in this section means the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."

The Act's definition of economic dispatch fails to give recognition to contractual, regulatory, and environmental limitations or requirements that will appropriately govern dispatch protocols. Further, the definition should be clarified to make clear that the reference to "operational limits" includes those necessary to maintain system reliability.

b. Geographic Scope of Economic Dispatch

The scale or area for which economic dispatch should be practiced is that geographic scale or area for which an entity has an obligation to serve whether that obligation arises from federal, state or local law, or under a long-term contract to provide electric service to end users or to a distribution utility.

c. Additional Factors Considered in Economic Dispatch

As noted above, contractual, regulatory, and environmental limits or requirements in addition to operational limits should be considered in economic dispatch.

Question 3

"How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please indicate what the difference is, how often this occurs, and its impact upon non-utility generation and upon retail electricity users. If you have specific analyses or studies that document your position, please provide them."

Response:

There are no basic differences in classes of generation for either utility or non-utility owned generation with the exception of PURPA required "must purchase" generation, for which dispatch requirements are contractually and administratively determined. For those LPPC member companies with PURPA obligations, PURPA units are included in the economic dispatch in accordance with their PURPA requirements and contract conditions rather than on economic merit order. With some limited exceptions, utilities are obligated to purchase all of the energy delivered by these units rather than according to economic dispatch. These administratively developed costs often differ significantly from the real time energy costs used in the economic dispatch of other generation. With the exception of these PURPA generators, all utility-owned generators and IPP generators under contract with LPPC members, and all resources purchased from outside of the utility's control area are dispatched to minimize the total system production cost.

Actual operational practices do not differ from the formal procedures required under tariff or federal or state rules. LPPC members recognize contractual, regulatory, and environmental limits and requirements of generation and transmission in addition to operational limits, which includes limits necessary to maintain system reliability.

Question 4

"What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by non-utility generators, please explain the changes you recommend."

Where it makes economic sense, LPPC members routinely engage in economic dispatch of utility and non-utility generation in a manner that is consistent with the provision of reliable power at least cost to their customers, consistent with operational limitations, contractual obligations, regulatory restrictions and environmental limitations. The operation of LPPC-member power systems within these parameters, and the determination of the least-cost protocols for governing dispatch decisions, are an integral part of operating a local distribution system.

Yet, notwithstanding LPPC members' commitment to least-cost reasonable economic dispatch for all generation, LPPC emphasizes that it can see no appropriate federal role in overseeing this process. Public power entities have every incentive to minimize their costs through the economic dispatch of available resources in order to satisfy their commitment to the provision of least-cost, reliable power. As a matter of law, there is no statutory authority for involving a federal agency in the purchasing decisions of otherwise non-jurisdictional utilities, such as LPPC members. Even for utilities subject to the full jurisdiction of the Federal Energy Regulatory Commission, LPPC emphasizes that the propriety of purchasing decisions of local distribution companies is outside federal jurisdiction.[1] These operations have been historically and appropriately overseen at the state level.

LPPC further emphasizes that any regulatory oversight of economic dispatch decision-making would involve the highly contentious matter of ascertaining the appropriate cost benchmarks for the process. The record of regulatory involvement in implementing the mandatory, ostensibly cost-based, purchasing scheme under Section 210 of the Public Regulatory Policies Act of 1978 ("PURPA") provides no confidence that this exercise may be conducted without risking the imposition of substantial costs on the very consumers the scheme is supposed to benefit.

For these reasons, LPPC strongly cautions against the use of this exercise in order to promote any additional regulation of economic dispatch.

Question 5

"If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to

---

[1] *See Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, at 972 (1986); citing *Pike County Light & Power Co. v. Pennsylvania Public Utility Commission*, 77 Pa.Commw. 268, 465 A.2d 735 (1983); *Kansas-Nebraska Natural Gas Co. v. State Corporation Commission*, 4 Kan.App.2d 674, 610 P.2d 121 (1980); *Kentucky-West Virginia Gas Co. v. Pennsylvania Public Utilities Commission*, 837 F.2d 600 (3d Cir. 1988).

energy prices and costs, to environmental emissions and other impacts? How would this affect retail customers in particular states or nationwide?"

Response:

LPPC members practice economic dispatch, defined within the parameters and constraints identified above, and the question is inapplicable. If one assumes that economic, environmental, reliability, regulatory or contractual restrictions can be ignored for the purpose of promoting non-utility generation, there will be associated negative impacts.

Question 6

"Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?"

Response

Properly defined and administered, economic dispatch should not have a negative impact on reliability. Promoting dispatch at the expense of reliability parameters will involve obvious risks. No statutory or regulatory steps should be taken that would promote economic dispatch in a manner that would conflict in any way with the reliability of the Nation's transmission system, a matter that Congress clearly instructed FERC in Section 1211 of the Energy Policy Act of 2005 is to be considered a priority.

We hope these responses are helpful and will aide in your consideration of this issue.

Sincerely,

Michele Mandell

Michele Mandell, Secretary, on behalf of
Frank C. McCamant
Chair, Electric Restructuring Task Force
Large Public Power Council

Attachment

cc: Ms. Alison Silverstein
Mr. Joe Eto
Mr. Dick Silverman

The Large Public Power Council
Member Companies

Austin Energy (TX)
Chelan County PUD (WA)
CPS Energy, formerly City Public Service (TX)
Clark Public Utilities (WA)
Colorado Springs Utilities (CO)
JEA (FL)
Knoxville Utilities Board (TN)
Long Island Power Authority (NY)
Los Angeles Department of Water and Power (CA)
Lower Colorado River Authority (TX)
Memphis Light, Gas and Water Division (TN)
Municipal Electric Authority of Georgia (GA)
Nebraska Public Power District (NE)
New York Power Authority (NY)
Omaha Public Power District (NE)
OUC (FL)
Platte River Power Authority (CO)
Puerto Rico Electric Power Authority (PR)
Sacramento Municipal Utility District (CA)
Salt River Project (AZ)
Santee Cooper (SC)
Seattle City Light (WA)
Snohomish County PUD (WA)
Tacoma Public Utilities (WA)